NON-PUBLIC?: N
ACCESSION #: 8907250110
LICENSEE EVENT REPORT (LER)

FACILITY NAME: Dresden Nuclear Power Station, Unit 3 PAGE: 1 of 33

DOCKET NUMBER: 05000249

TITLE: Turbine Trip and Reactor Scram on Stop Valve Closure Due to Slow Transfer of House Loads During Loss of Offsite Power
EVENT DATE: 03/25/89 LER #: 89-001-01 REPORT DATE: 07/10/89

OTHER FACILITIES INVOLVED: UNIT 2 DOCKET NO: 05000237

OPERATING MODE: N POWER LEVEL: 089

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION
50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:
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COMPONENT FAILURE DESCRIPTION:
CAUSE: X SYSTEM: FK COMPONENT: CAP MANUFACTURER: I005
X EA 52 G080
X EC 52 G080
X BJ MO G080
X IA OJX 5250

REPORTABLE NPRDS: N
Y
Y
Y
N

SUPPLEMENTAL REPORT EXPECTED: No

ABSTRACT:

At approximately 0133 hours on March 25, 1989, while Unit 3 was operating at 89% rated core thermal power, a fault occurred within 345 KV switchyard power circuit breaker (PCB) 8-15. Local Breaker Backup logic circuitry then automatically isolated PCB 8-15; this de-energized Unit 3 reserve auxiliary transformer (TR) 32, causing a loss of offsite power (LOOP) to Unit 3. The automatic transfer of 4 KV Bus 32 from TR 32 to Unit 3 auxiliary TR 31 did not occur quickly enough to prevent undervoltage trips of the 38 reactor feed pump (RFP) and the 38 reactor recirculation pump. When the standby 3C RFP automatically started, reactor water level rose to the main turbine and RFP trip setpoint and a reactor scram on turbine stop valve closure resulted. The Main Steam Isolation Valves (MSIVs) were manually closed to conserve reactor inventory and the Isolation Condenser was used for reactor pressure control. Mildly contaminated condensate was initially used to supply

the Isolation Condenser shell side because the clean demineralized water supply valve was unavailable. This resulted in low level contamination to the area surrounding the Isolation Condenser vent. Cold shutdown conditions were achieved by 2230 hours on March 25, 1989. Corrective actions included inspection, testing and repair of various breakers and logic circuits and surveys/cleanup of the areas affected by the Isolation Condenser vent. Conservative calculations found the release was less than 0.01% of 10CFR20 Appendix I Quarterly Objectives. Safety significance was minimal as the Automatic Depressurization and Core Spray Systems were available. A previous LOOP event involving Unit 2 was reported by LER 85-34/050237.

END OF ABSTRACT

Figure "Licensee Event Report Component Failure Described" omitted.

Description append on the LERFORM.

PLANT AND SYSTEM IDENTIFICATION:

General Electric - Boiling Water Reactor - 2527 MWt rated core thermal power,

Nuclear Tracking System (NTS) tracking code numbers are identified in the text as (XXX-XXX-XX-XXXXX).

EVENT IDENTIFICATION:

Turbine TA! Trip and Reactor Scram on Stop Valve Closure Due to Slow Transfer

of House Loads During a Loss of Offsite Power Event.

A. CONDITIONS PRIOR TO EVENT:

Unit: 3 Event Date: March 25, 1989 Event Time: 0133 hours

Reactor Mode: N Mode Name: Run Power Level: 89%

Reactor Coolant System (RCS) Pressure: 972 psig

B. DESCRIPTION OF EVENT:

At approximately 0133 hours on March 25, 1989, while Unit 3 was operating

at 89% rated core thermal power, an internal fault occurred within 345 KV power circuit breaker (PCB) 8-15 FK! located in the 345 KV switchyard

FK!. The configuration of the 345 KV switchyard is shown in Figure 1. Reactor Feed Pumps (RFPs) SJ! 3A (powered from 4 KV Bus 31 EA!) and 36 (powered from 4 KV Bus 32 EA!) were operating. The 3C RFP was selected as the standby RFP (4 KV Bus 32 was selected as the standby power source). A simplified Unit 3 electrical arrangement is provided in Figure 2. The 3A feedwater regulating valve (FWRV) JB! was operating

in the automatic mode, and the 3B FWRV was operating in the manual mode at approximately 25% open. A detailed sequence of events is provided in Table 1.

Significant occurrences during this event that were investigated are as follows:

1. Power Circuit Breaker (PCB) 8-15 Fault.

A phase-to-ground fault occurred and gave a trip signal for PCB 8-15. Because the fault did not clear, Local Breaker Backup logic circuitry automatically tripped additional breakers to isolate 345 KV Busses 8 and 15. Because reserve auxiliary transformer (TR) 32 EA! is fed from 345 KV Bus 8, power to TR 32 was lost.

2. Slow Transfer of Bus 32 from TR 32.

Bus 32 should have promptly transferred to TR 31 (EA! (see Figure 2). During this event approximately 14 seconds elapsed between the tripping of Bus 32 feed breaker 152-3205 from TR 32 to the closing of Bus 32 feed breaker 152-3201 from TR 31.

3. Open Annunciator Panel Fuses.

At 0435 hours with Unit 2 in the Run mode at 97% rated core thermal power, the Nuclear Station Operator (NSO) discovered that alarm F-12, Alarm Potential F-9 Failure, on the 902-3 annunciator panel JF! was illuminated. This alarm, which corresponds to an open F-9 fuse and subsequent loss of power to the 902-3 annunciator panel, is believed to have existed since 0134 hours when the Unit 3 main generator tripped. The 902-6 annunciator panel fuse is also believed to have opened at 0134 hours.

Loss of the 902-3 annunciator panel for longer than 30 minutes should lead to the declaration of a Generating Station Emergency Plan (GSEP) Alert condition in accordance with Emergency Plan Implementation Procedure (EPIP) 200-T1, Classification of GSEP Conditions. The loss of the 902-6 annunciator panel did not require

entry into the GSEP emergency action levels.

4. Feedwater Control System JB! Behavior.

When the Bus 32 undervoltage condition occurred due to the slow transfer of Bus 32 from TR 32 to TR 31, the 38 RFP automatically tripped. This caused feedwater flow through the 3A RFP to exceed 5.6 E6 1b/hr, thereby initiating the Feedwater System runout flow control mode JB!. Runout flow control mode is a feature of the feedwater level control system designed to automatically limit feedwater flow such that RFP trips on overcurrent or low suction pressure are prevented. Runout flow control mode is entered at 5.6E6 1b/hr feedwater flow or below +20 inches reactor water level (instrument zero reference). Normally, at the initial power level, loss of a single RFP without automatic start of the standby RFP would have caused a reactor scram on low water level (setpoint: +8 inches above instrument zero). (Note: instrument zero reference is 143 inches above the top of active fuel). However, since the loss of the 38 RFP was accompanied by a trip of the 38 reactor recirculation AD! pump (also powered via Bus 32), reactor power decreased and the resultant reactor water level swell minimized the reactor level descent caused by loss of the 3B RFP. Reactor water level dropped to approximately +16 inches above instrument zero; however, the standby 3C RFP failed to start immediately due to Bus 32 being de-energized. After approximately 11 seconds the Bus 32 transfer process completed; this energized the standby 3C RFP. Since reactor water level was still less than +20 inches the runout flow control mode was still in effect, resulting in two RFPs supplying 11.2E6 1b/hr feedwater flow to the reactor vessel. Attempts by the NSO to close the feedwater regulating valves (FWRVs) at this time were thus prohibited by the runout flow control feature. As reactor water level increased rapidly and passed the +20 inches level, the runout flow control mode automatically reset, allowing the FWRVs to return to their normal operating positions as selected prior to the event. As the FWRVs closed, water level continued to rise until at +55 inches reactor water level the main turbine and RFPs automatically tripped. A reactor scram on turbine stop valve closure then resulted.

5. Spurious Trip of Bus 39 EC! to Motor Control Center (KC) 38-7/39-7 EC! Breakers.

Feed Breakers 252-3971 and 252-3972 EC!, from 480 V Bus 39 to the Low Pressure Coolant Injection (LPCI) (BO) swing bus Motor Control Center (KC) 3
-7/39-7! EK!, spuriously tripped. This
was abnormal since a transfer of the power feed to the LPCI swing bus from 480 V Bus 39 to 480 V Bus 38 should not occur until an undervoltage condition exists on Bus 39 EL! for 15 seconds. Undervoltage on Bus 39 existed for only seven seconds (elapsed time between loss of TR 31 to loading of the Unit 3 Diesel Generator

EK!).

6. Failure of MCC 38-7/39-7 Reserve Feed Breaker 252-3872 to close.

Following the spurious trip of feed breakers 252-3971 and 252-3972, reserve feed breaker 252-3872 EC! failed to close. Consequently, MCCs 38-7 and 39-7 remained de-energized.

7. Use of Contaminated Condensate KA! Isolation Condenser BL! Shell Side Supply.

During the first initiation of the Isolation Condenser, the Nuclear Station Operator (NSO) observed that the clean demineralized water KC! shell side supply valve M03-4399-74 was de-energized (see Figure 3). Consequently, the NSO initiated use of the mildly contaminated condensate Isolation Condenser shell side supply under direction of Shift Supervision.

During the second initiation of the Isolation Condenser, valve M03-4399-74 had been opened, but the available clean demineralized water pump could not keep up with demand. Therefore, the NSO supplemented the clean demineralized water supply with the mildly contaminated condensate supply.

8. High Pressure Coolant Injection (HPCI) BJ! Lube Oil Cooling Problem.

At approximately 0400 hours while using the HPCI System for reactor pressure and water inventory control, annunciator D-10, HPCI High Pressure Bearing Oil Drain High Temperature, on the 903-3 panel alarmed. The NSO then immediately began to perform the operator actions listed in Dresden Operating Annunciator Procedure (DOA) 920(3)-3 D-10, HPCI High Pressure Bearing Oil Drain High Temperature. The annunciator continued to alarm (setpoint: 18 deg F increasing temperature). The NSO then reviewed the HPCI System valve alignment and noted that the M03-2301-49 valve, HPCI Lube Oil Cooling Water Test return valve to the condensate storage tank, was open. The NSO also noted that the M03-2301-48 valve, HPCI lube oil cooling water normal return valve to the HPCI booster pump discharge, was closed. The NSO proceeded to close the M03-2301-49 valve and open the M03-2301-48 valve after which annunciator D-10 reset.

The HPCI System subsequently tripped due to a +48 inches (instrument

zero reference) reactor water level signal. Discussions with the NSO indicated that his concern with the lube oil cooling problem allowed reactor water level to attain the +48 inch HPCI trip setpoint earlier than expected.

9. Bus 34-1 to Bus 34 Breaker Problem.

When the initial attempt was made to backfeed Bus 34 EA! from the Unit 3 Diesel Generator (DG 3), the Bus 34-1 EK! to Bus 34 feed breaker 152-3403 EA! tripped open when the breaker was initially closed at approximately 0405 hours. Operations Department

personnel succeeded in closing breaker 152-3403 at approximately 0530 hours.

10. HPCI Turning Gear Motor Failure.

The HPCI turning gear was unavailable following the trip of the HPCI turbine because of turning gear motor failure. Consequently, Operations Department personnel turned the HPCI turbine manually to insure proper HPCI turbine cooldown.

11. Open fuse for Security IA! Multiplexer MUX! 8.

Security MUX 8 was unavailable for approximately one hour during the event due to an open power supply fuse. The Security force promptly initiated appropriate compensatory measures upon loss of MUX 8 in accordance with the security plan.

12. Security Uninterruptible Power Supply (UPS) Failure.

The security computer was without power for approximately 17 minutes

during the event when the Security System UPS failed during an attempt to switch the security bus back to main power. The Security

force promptly initiated appropriate compensatory measures upon failure of the Security System UPS in accordance with the security plan.

13. Primary Containment NH! Oxygen Analyzer IK! Unavailability.

The Primary Containment oxygen analyzer read zero at each sample point for a short period following restoration of power.

14. Instrument Air System LO! Behavior.

Upon loss of the Unit 3 Instrument Air System at approximately 0148 hours, the main turbine turning gear was rendered inoperable until 0510 hours at which time the Unit 3 Instrument Air System was supplied by the Unit 1 Instrument Air System.

Additionally, operator action was required to prevent depressurization of the Unit 2 Instrument Air System via the 3C Instrument Air Compressor, which may be aligned to Unit 2 or Unit 3. The 3C Instrument Air Compressor was manually isolated from the Unit 2 Instrument Air System.

C. APPARENT CAUSE OF EVENT:

This report is submitted in accordance with 10CFR50.73(a)(2)(iv), which requires the reporting of any uplanned Engineered Safety Feature (ESF) actuation, including the reactor protection system (RPS).

The Shift Engineer promptly notified Station Management and the Operations Duty Supervisor of this event; a support team was then assembled to assist with root cause evaluation, repairs, testing, and other corrective actions. The root cause of the reactor scram has been attributed to the slow transfer of 4 KV Bus 32 from TR 32 to TR 31, causing a reactor water level transient which resulted in an automatic main turbine trip on high reactor water level and a subsequent turbine stop valve closure reactor scram signal. Cause analyses of the significant occurrences observed during this event are provided below.

1. Power Circuit Breaker (PCB) 8-15 Fault.

Inspection of PCB 8-15 revealed that a ground capacitor in the A phase of the circuit breaker had failed and that a phase-to-ground

fault had occurred across an adjacent insulated support column (see Figure 4). The phase compartments of PCB 8-15 are pressurized with sodium hexafluoride gas (SF sub 6)- The failed ground capacitor

(which was mounted within the A phase pressure vessel) utilized a mineral oil dielectric fluid which contained no polychlorinated biphenyls. As the phase compartment pressure vessels remained intact, no release of SF sub 6 gas or ground capacitor dielectric fluid occurred. Debris from the capacitor included pieces of insulation and metal plates. Most of the oil and debris from the failed capacitor remained in the A phase pressure vessel, but some passed through a connecting duct to the B and C phase pressure vessels. The apparent cause of the phase-to-ground fault within the A phase circuit breaker was the capacitor failure and resultant debris.

2. Slow Transfer of Bus 32 from TR 32 to TR 31.

The proximate cause of the slow closure of breaker 152-3201 was attributed to dirty contacts on the breaker up/down position switch.

The maintenance history for this breaker indicates that the last overhaul of this breaker was on February 11, 1982, and was next due by December 30, 1989. The root cause of this breaker problem is attributed to the long interval between breaker overhauls.

3. Open Annunciator Panel Fuses.

The probable cause of the open annunciator panel fuses was an apparent spike within the 125 VDC System following the loss of offsite power on Unit 3.

The failure of the NSO to discover the 902-3 annunciator panel problem until 0435 hours is attributed to personnel error. The NSO incorrectly identified the "Alarm Potential F-9 Failure" alarm (Panel 902-3; Alarm F-12) as an adjacent Primary Containment Nitrogen Inerting Makeup System high flow alarm (Panel 902-3; Alarm G-13) and determined that the alarm did not require immediate operator action. Contributing to this error was the need to clear numerous annunciator alarms following the loss of offsite power on Unit 3 and the lack of distinctive backlighting of annunciator windows for loss of annunciator panel alarms.

4. Feedwater Control System Behavior.

Loss of an RFP without automatic start of the standby RFP at initial

conditions of 89% rated thermal power would normally be expected to result in an automatic reactor scram on low reactor water level (setpoint: +8 inches above instrument zero). However, in this event a concurrent trip of the 38 reactor recirculation pump occurred. This caused a reactor power decrease and reactor water level swell such that the minimum reactor water level prior to the reactor scram was approximately +16 inches.

The feedwater level control system was unable to prevent a rapid reactor water level increase to the automatic main turbine and RFP trip setpoint (+55 inches above instrument zero) due to inherent

design aspects of the runout flow control feature, which operated as designed to prevent loss of the RFPs on overcurrent and/or low suction pressure trip signals. However, review of this event indicates that additional operator training on the runout flow control feature would assist the reactor operators during this type of event. Additionally, design setpoint changes to the runout flow control feature may be postulated to provide improved feedwater level control in this type of event.

5. Spuri
us Trip of Bus 39 to MCC 38-7/39-7 Breakers.

A General Electric (GE) CR122AT Time Delay on Energization (TDOE) relay transfers the power feed to the LPCI swing bus from Bus 39 to Bus 38 (see Figure 2). The root cause of the spurious trip of breakers 252-3971 and 252-3972 has been attributed to an original

construction design deficiency in that the model TDOE relay used was not suitable for this application. This conclusion is based on the investigation discussed below.

When an undervoltage condition exists on Bus 39, the UV contacts (see Figure 5) pick up and the "HFA" (227B39X1) relay becomes energized. HFA (227B39X1) contacts 11-12 and 5-6 close sealing in the coil while contact 3-4 closes starting the 15 second timer on the TDOE relay. If the undervoltage on Bus 39 remains for 15 seconds, TDOE contacts 3-4 and 1-2 close, tripping feed breakers 252-3971 and 252-3972 while closing reserve feed breakers 252-3871 and 252-3872. If voltage is restored to the bus before the 15 second time delay expires, the OVX contact closes, the OVX coil energizes, and the OVX contact opens. With the OVX contact open, power to the TDOE is lost and the timer should reset. During this event an undervoltage existed on Bus 39 for only seven seconds; nevertheless, the circuit responded as if the 15 second delay had been reached.

The OVX and TDOE relays were tested in accordance with Work Request 83559. The OVX contact was verified to open properly for simulated undervoltage conditions of two, five, seven, and 10 seconds. The TDOE relay was then tested for the same simulated undervoltage conditions by monitoring the voltage across TDOE contacts 3-4 and 1-2. The results of the test are contained in Table 2.

when a simulated undervoltage condition existed for greater than 15 seconds, breaker 252-3971 tripped and breaker 252-3871 closed as expected. When the simulated undervoltage condition existed for two seconds, the breakers were unaffected and the TDOE relay reset as expected. However, when the simulated undervoltage condition was present for five, seven, or 10 seconds, breakers 252-3971 and 252-3871 did not respond as expected.

Subsequently, a review of a GE catalog description revealed that inputs to the GE CR122AT relay for over 1/3 of the time setting will produce a momentary output from the timer upon removal of the input signal prior to completion of the delay. The momentary output from the timer explained the simulated undervoltage test results obtained for the GE CR12ZAT TDOE relay. Based on the test results and the catalog description, it was determined that the GE CR122AT TDOE relay was unsuitable for this application.

6. Failure of MCC 38-7/39-7 Reserve Feed Breaker 252-3872 to Close.

The proximate cause of the failure of breaker 252-3872 to close was attributed to a breaker linkage that was found to be sticking intermittently. Breaker 252-3872, which is located at MCC 38-7, is not currently inc in the preventative maintenance program. A modification had been approved for replacement of Breaker 252-3872

with an improved contactor assembly; this modification work is scheduled for com on during the upcoming Unit 3 D3R11 refuel outage.

The root cause of the Breaker 252-3872 failure was therefore attributed to the lack of a periodic preventative maintenance requirement.

7. Use of Contaminated Condensate Isolation Condenser Shell Side Supply.

The clean demineralized water shell side supply valve M03-4399-77 is powered by MCC 39-3 (see Figure 2). The reason that this valve was initially de-energized during this event is that MCC 39-3 is designed to automatically trip during undervoltage conditions to limit loads on the emergency Diesel Generators.

After power was restored to MCC 39-3, the one available clean demineralized water pump could not keep up with the Isolation Condenser demand. Based on this event and previous experience with operation of the Isolation Condenser for reactor pressure control following a Unit scram, the clean demineralized water supply

to the Isolation Condenser is judged to be undersized; the root cause of the need to use contaminated condensate Isolation Condenser

shell side supply is therefore attributed to design deficiency.

8. HPCI Lube Oil Cooling Problem.

During a HPCI System automatic initiation, the M03-2301-48 valve is automatically opened and the M03-2301-49 valve is automatically closed (see Figure 6). This allows lube oil cooling water to be supplied by the HPCI booster pump discharge and returned to the suction. During normal operation with HPCI in the standby mode, the M03-2301-48 valve is closed and the M03-2301-49 valve is open. This allows a flow path to the Condensate Storage Tank KA!, through

the M03-2301-15 valve for the Gland Seal Leak Off Drain pump.

During this event, the HPCI System was manually initiated primarily as a means of pressure control and secondly as a means of inventory control. Therefore, according to Dresden Operating Procedure (DOP) 2300-3, HPCI System Manual Startup and Operation, the NSO manually initiated HPCI and utilized the M03-2301-10 valve and the manual flow controller to adjust HPCI flow. Subsequent steps of BOP 2300-3

direct the NSO to open the 3-2301-" valve and close the 3-2301-49 valve. DOS

2300-3 did not instruct the NSO to perform these subsequent steps in rapid succession, however. Therefore, since the NSO's primary concern was maintaining the reactor in a safe condition, he remained

at the HPCI flow adjustment step and did not immediately close the 3-2301-49 valve and open the 3-2301-48 valve. Not performing these steps caused the lube oil cooler flow to be dead-headed against the 3-2301-21 check valve. (The downstream side of the 3-2301-21 check valve experiences full HPCI pump flow and pressure).

During this event HPCI discharge pressure was approximately 800 psig.

In conclusion, the root cause for HPCI lube oil cooling problem is attributed to procedural deficiency as DOP 2300-3 did not require

prompt respositioning of the M03-2301-48 and M03-2301-49 valves upon manually initiating the HPCI system for purposes of reactor pressure control.

9. Bus 34-1 to Bus 34 Breaker Problem.

The proximate cause of the failure of breaker 152-3403 to trip open following its closure was attributed to pitted overvoltage contacts found on undervoltage relay 127-2-834. Because the overvoltage contacts did not close upon Bus 34 voltage restoration by DG 3, undervoltage relay 127-2-834 could not be de-energized and reset; consequently, the trip signal to breaker 152-3403 remained. The maintenance history for this relay indicates that this relay was last cleaned on may 15, 1988. Normal wear since the last relay cleaning is therefore attributed as the root cause of this breaker problem.

10. HPCI Turbine Gear Motor Failure.

Subsequent to the removal of the HPCI turning gear motor, total disassembly and inspection revealed that the motor commutator was excessively pitted and worn. An inspection of the motor brushes indicated that one of the two brushes was installed slightly out of alignment. Figure 7 shows the correct and as found brush installation configurations. The misaligned installation allowed less brush surface area to come in close proximity of the motor commutator. This is believed to have allowed excessive arcing and heat generation, ultimately resulting in degradation of the motor commutator.

A review of Dresden Electrical Procedure (DEP) 8300-4, Unit 2/3 Inspection of DC Motors and Brushes, indicated that there are no cautions that state the brushes must be reinstalled to match the commutator contour. Therefore, the root cause of these event is attributed to procedural deficiency. DEP 8300-4 was last performed on the HPCI turning gear motor on May 12, 1988.

11. Open Fuse for Security Multiplexer (MUX) 8.

No abnormal conditions were identified that would have caused the fuse to open. The root cause of this failure is therefore attributed to normal end-of-life of this component.

12. Security UPS Failure.

The Security UPS failed during an attempt to switch the security bus back to main power. No formal procedure existed to guide the operator in this evolution. The proximate cause of the failure is attributed to an inappropriate switching sequence. The root cause of this failure is attributed to procedural deficiency in that a detailed procedure for switching the security UPS was not available.

13. Oxygen Analyzer Unavailability.

The abnormal readings of the oxygen analyzer are attributed to normal cooldown of the oxygen analyzer following loss of power. The calibration of the oxygen analyzer is temperature sensitive, and the abnormal readings upon restoration of power resulted.

14. Instrument Air System Behavior.

The proximate cause of the main turbine Turning gear engagement problem was determined to be the fact that the turning gear assembly requires instrument air for automatic engagement.

Investigation revealed that the main turbine turning gear can be manually engaged without instrument air supply. However, Dresden Operating Abnormal (DOA) Procedure 4700-1, Instrument Air System Failure, did not include instructions concerning manual engagement of the main turbine turning gear. Therefore, the root cause of the turning gear engagement problem was attributed to procedure deficiency. The root cause behind the unexpected need for operator action to manually isolate the 3C Instrument Air Compressor from the Unit 2 Instrument Air System was also attributed to procedure deficiency as DOA 4700-1 did not include appropriate instructions.

D. SAFETY ANALYSIS OF EVENT:

A safety analysis of each significant occurrence associated with this event is provided below.

1. Power Circuit Breaker (PCB) 8-15 Fault.

The failure of PCB 8-15 led to the reactor scram and loss of offsite

power. The safety significance of this failure was minimized by the fact that the Unit 3 and 2/3 DGs started and loaded and were capable of carrying the necessary safety system loads.

2. Slow Transfer of Bus 32 from TR 32 to TR 31.

The slow closure of breaker 152-3201 resulted in the trip of the 38 RFP, the trip of the 38 reactor recirculation (recirc) pump motor generator (MG) set, the delayed automatic start of the 3C RFP (in standby), and the subsequent Unit scram and loss of offsite power. The safety significance of this slow closure is minimized by the fact that the Unit 3 and 2/3 DGs started and loaded and